VOLUME VIII: CHAPTER 1

METHODS FOR ESTIMATING CARBON DIOXIDE EMISSIONS FROM COMBUSTION OF FOSSIL FUELS

October 1999

Prepared by:
ICF Incorporated

Prepared for:
Greenhouse Gas Committee
Emission Inventory Improvement Program

DISCLAIMER

This document was prepared for the Emission Inventory Improvement Program and the U.S. Environmental Protection Agency by ICF Incorporated, Washington, D.C. This report is intended to be a working draft document and has not been reviewed or approved for publication. The opinions, findings, and conclusions are those of the authors and not necessarily those of the Emission Inventory Improvement Program or the U.S. Environmental Protection Agency. Mention of company or product names is not to be considered an endorsement by the Emission Inventory Improvement Program or the U.S. Environmental Protection Agency.

ACKNOWLEDGMENTS

This document was prepared by Randy Freed, Michael Gillenwater, Anne Choate, William Driscoll and other staff of the ICF Consulting Group, Washington, D.C., for the Greenhouse Gas Committee of the Emission Inventory Improvement Program and for Ethan McMahon and Wiley Barbour of the Office of Policy of the U.S. Environmental Protection Agency. In addition, Art Rypinski of the U.S. Department of Energy's Energy Information Administration (EIA) provided invaluable assistance in explaining EIA data on fossil fuel combustion. Members of the Greenhouse Gas Committee contributing to the preparation of this document were:

Mike Aucott, Program Analyst, New Jersey Department of Environmental Protection
Peter Ciborowski, Environmental Protection Specialist, Minnesota Pollution Control Agency
Guido Franco, Program Analyst, California Energy Commission
Don LaTourette, Program Analyst, New Hampshire Department of Environmental Services
Joe Loyer, Program Analyst, California Energy Commission
Sam Sadler, Energy Analyst, Oregon Department of Energy

CONTENTS

TABLES, FIGURES

TABLES, FIGURES (CONTINUED)

1

INTRODUCTION

The purposes of the preferred methods guidelines are to describe emissions estimation techniques for greenhouse gas sources in a clear and unambiguous manner and to provide concise example calculations to aid in the preparation of emission inventories. This chapter describes the procedures and recommended approaches for estimating carbon dioxide emissions from combustion of fossil fuels. Companion chapters describe methods for estimating emissions of carbon dioxide and other greenhouse gases (methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride) from a variety of other sources.

Section 2 of this chapter contains a general description of the fossil fuel combustion source category. Section 3 provides a listing of the steps involved in using the preferred estimation method to estimate carbon dioxide emissions. Section 4 of this chapter presents the preferred estimation method; Section 5 is a placeholder section for alternative emission estimation techniques that may be added in the future. Quality assurance and quality control procedures are described in Section 6. References used in developing this chapter are identified in Section 7.

2

SOURCE CATEGORY DESCRIPTION

2.1 EMISSION SOURCES

Energy-related activities are the most significant contributor to U.S. greenhouse gas emissions, accounting for nearly 88 percent of total emissions in 1995. Emissions from fossil fuel combustion comprise the vast majority of these energy-related emissions. Fossil fuel is combusted to heat residential and commercial buildings, generate electricity, produce steam for industrial processes, and power automobiles and other vehicles. As fossil fuels burn, they emit carbon dioxide (CO_2) as a result of oxidation of the carbon in the fuel. Other gases that are precursors of CO_2, such as carbon monoxide (CO) and nonmethane volatile organic compounds (NMVOCs), are emitted as by-products of incomplete combustion. These gases are then oxidized to CO_2 over periods ranging from a few days to 10 years or more. For purposes of most greenhouse gas inventories, emissions of these other gases are counted as CO_2 emissions. That is, all carbon emitted to the atmosphere is reported as CO_2 emissions, even though a very small portion of the carbon will be emitted as these other gases. By reporting emissions in this fashion, state estimates of CO_2 will reflect total loadings of carbon to the atmosphere.

Carbon emissions occur from a number of activities associated with the production and transportation of energy, not all of which are accounted for in energy and non-energy uses of fossil fuels. These activities include venting and flaring, leakage of natural gas during the transmission and distribution of oil and natural gas, methane emissions from coal mines, and burning of coal in coal deposits. The first three of these activities - gas venting and flaring, gas leakage during the transmission and distribution of oil and natural gas, and methane emissions from coal mines - are addressed in chapters on these topics. Emissions from the burning of coal in coal deposits are highly variable from one state to another and are a very minor portion of total emissions. At this time, there is no recommended methodology to estimate emissions from this source.

2.2 FACTORS INFLUENCING EMISSIONS

The amount of CO_2 emitted from fossil fuel depends on the type and amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. This relationship can be described in two parts:

1) The amount of carbon contained in the fuel per unit of energy produced varies for different fuel types. For example, coal contains the highest amount of carbon per unit of energy. For petroleum the amount of carbon per unit of energy is about 80 percent of that for coal; for natural gas, it is about 55 percent. Even within fuel types, carbon contents will vary, *e.g.*, lower quality coal (such as lignite and sub-

bituminous coal), has a higher carbon content coefficient (*i.e.*, more carbon emitted per unit of energy). There are similar carbon differences among the different types of liquid fuels and natural gas as well.

2) Not all carbon in fuel products is oxidized to CO_2, for two reasons. First, inefficiencies in the combustion process leave carbon unburned, which causes a small fraction of the carbon to remain unburned as soot or ash. As noted earlier, some carbon is not immediately oxidized to CO_2, and is emitted in the form of other hydrocarbons. Second, fossil fuels are also used for non-energy purposes, primarily as a feedstock for such products as fertilizer, lubricants, and asphalt. In some cases, as in fertilizer production, the carbon from the fuels is oxidized quickly to CO_2. In other cases, as in asphalt production, the carbon is sequestered in the product, sometimes for as long as several centuries.

The methods for estimating CO_2 emissions from combustion of fuels revolve around these two factors.

3

OVERVIEW OF AVAILABLE METHODS

Fossil fuels include coal, oil, and natural gas.[1] To estimate state emissions of carbon dioxide from fossil fuels, eight steps should be performed:

1) obtain the required energy data;
2) estimate the total carbon content of the fuels;
3) estimate the total carbon stored in products;
4) estimate the carbon potentially emitted from bunker fuel consumption;
5) estimate the carbon emissions associated with net imports of electricity;
6) calculate net potential carbon emissions;
7) estimate the carbon actually oxidized from energy uses; and

Methods for developing greenhouse gas inventories are continuously evolving and improving. The methods presented in this volume represent the work of the EIIP Greenhouse Gas Committee in 1998 and early 1999. This volume takes into account the guidance and information available at the time on inventory methods, specifically, U.S. EPA's *State Workbook: Methodologies for Estimating Greenhouse Gas Emissions* (U.S.EPA 1998a), volumes 1-3 of the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC, 1997), and the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 1996* (U.S. EPA 1998b).

There have been several recent developments in inventory methodologies, including:

- Publication of EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 1997* (U.S. EPA 1999) and completion of the draft inventory for 1990 – 1998. These documents will include methodological improvements for several sources and present the U.S. methodologies in a more transparent manner than in previous inventories;
- Initiation of several new programs with industry, which provide new data and information that can be applied to current methods or applied to more accurate and reliable methods (so called "higher tier methods" by IPCC); and
- The IPCC Greenhouse Gas Inventory Program's upcoming report on Good Practice in Inventory Management, which develops good practice guidance for the implementation of the 1996 IPCC Guidelines. The report will be published by the IPCC in May 2000.

Note that the EIIP Greenhouse Gas Committee has not incorporated these developments into this version of the volume. Given the rapid pace of change in the area of greenhouse gas inventory methodologies, users of this document are encouraged to seek the most up-to-date information from EPA and the IPCC when developing inventories. EPA intends to provide periodic updates to the EIIP chapters to reflect important methodological developments. To determine whether an updated version of this chapter is available, please check the EIIP site at http://www.epa.gov/ttn/chief/eiip/techrep.htm#green.

[1] Carbon dioxide is also emitted during combustion of biomass fuels (e.g., wood, ethanol, charcoal, bagasse, agricultural wastes, and vegetal fuels such as soybean-based diesel fuel and "black liquor" from wood -- a fuel used in paper mills). In the U.S., biomass fuels are generally grown on a sustainable basis. Under the GHG emission estimation guidelines prepared by the Intergovernmental Panel on Climate Change (IPCC), carbon dioxide emissions from biomass fuels grown sustainably are not counted. Therefore, the method described in this chapter does not address biomass fuels as a source of GHGs. For cases where biomass fuels are not grown sustainably, the GHG impact should be captured as a land use change; the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* provides information on how to do so.

8) convert net carbon emissions from energy consumption to total CO_2 emissions.

These eight steps are outlined in Section 4 below. The method described in this chapter is more data-intensive and detailed than most of the other GHG estimation methods. There are three reasons for this:

1) The US Department of Energy's Energy Information Administration (EIA) collects detailed energy use statistics, which are available at the state level,
2) CO_2 from energy use is the principal source of GHG emissions at the state and national level, and
3) A detailed analysis of energy-related emissions provides insight on mitigation opportunities for this important sector.

The methods described here are taken from the report by the Intergovernmental Panel on Climate Change (IPCC) entitled *IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 1997). These methods are used in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1997* (U.S. EPA 1999).

The results of applying the method described in this section, using state energy data compiled by EIA, may be viewed for each state on EPA's *State Climate Change Database*, at http://www.epa.gov/globalwarming .

4

PREFERRED METHOD FOR ESTIMATING EMISSIONS

To calculate CO_2 emissions from fossil fuel combustion,[2] the following data elements are needed:

1) Fossil fuel consumption by energy type;
2) Carbon content coefficients;
3) Carbon sequestered in products for long periods of time;
4) [Optional, if state data are available: carbon emitted from bunker fuel consumption];
5) Carbon emitted from net imports of electricity; and
6) Percentage of carbon oxidized during combustion.

A worksheet has been provided (see Table 1.4-1) to assist in organizing the data and calculations.[3]

Because the carbon content of fossil fuels varies by fuel type, it is necessary to compile consumption data for each type of fuel consumed. A recommended list of fuels is provided in Table 1.4-2. Note that certain primary fuels (such as crude oil) do not appear on this list. This is because primary fuels of this nature are not combusted directly, but rather are transformed into secondary fuels (such as gasoline) which are combusted. Therefore, the carbon in these primary fuels is accounted for in the secondary fuels.

Fuel statistics should be provided on an energy basis (preferably in million Btu) rather than weight, because considerable variation exists in the energy content per weight of fossil fuels. All energy data refer to gross caloric values (also called higher heating value) and not to net caloric value (lower heating value) to allow for accurate and transparent emissions estimates. Statistics using other units, such as barrels or short tons, may be used, but require conversion to energy units. If conversion is necessary, the conversion factors used should be reported. Default conversion factors for the various fuel types are presented in Table 1.4-2. Note that these

[2] As noted above, for this discussion, CO_2 emissions from fossil fuel combustion include all of the carbon in fuels that is either immediately oxidized or oxidized within a short time period (*i.e.*, less than 20 years). It thus includes carbon in the form of gases, like CO and CH_4. It also includes short- lived products that will be burned after use or decompose quickly. CH_4 emissions from oil and gas production and coal mining, as well as CH_4, CO, N_2O, NO_X and NMVOC emissions from stationary and mobile source combustion are not included in this section but are discussed later (see Chapters 3 and 4).

[3] An electronic version of the worksheet in Excel format is available from EPA's State and Local Climate Change Program and is also available on the Internet at *http://www.epa.gov/globalwarming*.

conversion factors are national averages based on data from the early 1990s and may not accurately reflect the energy content of fuels used in a particular state or for more recent years. The degree of variation geographically and temporally is less significant for natural gas and refined petroleum fuels than for coal, which may vary significantly from mine to mine and year to year.[4] State-specific thermal conversion factors for coal are compiled by EIA, and presented in a variety of sources. For example, representative energy-content information based on a survey of electric utility power plants is contained in EIA's annual *Cost and Quality of Fuels for Electric Utility Plants* (EIA 1997a), while more general information is provided in the *Quarterly Coal Report* (EIA 1997b) and *State Energy Data Report* (EIA 1997c).

Next, fuel consumption data should be disaggregated into the following consumption sectors: residential, commercial, industrial, transportation, and electric utility. Sector-specific consumption figures for all 50 states may be found in *State Energy Data Report* (EIA, 1997c). In many instances, states may find it useful to distribute emissions from electric utilities across "end-use sectors," to assist in formulating emission reduction strategies. To distribute utility emissions accurately, it is necessary to obtain electricity consumption data by each of the four end-use sectors (residential, commercial, industrial, and transportation) in the state. Default values for the percentage of electricity used by each sector may be obtained from *State Energy Data Report* (EIA, 1997c). Using these figures, states can calculate the fraction of total electricity consumption which is consumed by each of the four end-use sectors (*i.e.*, each of these fractions is multiplied by total emissions from the utility sector, resulting in the portion of utility emissions attributable to each end-use sector). The end-use emissions from electricity consumption are then added to the other sectoral emissions.

The estimation methodology consists of eight steps, as presented below.

Step (1) Obtain Required Energy Data (Table 1.4-1, Column A)

- *Required Energy Data.* The information needed to perform these calculations is annual state energy consumption data based on *fuel type* (*e.g.,* gasoline, residual oil, bituminous coal, lignite, natural gas, etc.) by *sector* (*e.g.,* residential, commercial, industrial, transportation, and electric utility). A list of suggested sector/fuel categories is provided in Table 1.4-1. Additionally, further disaggregation may be done (*i.e.*, by individual industries within the industrial sector or by specific fuel types not listed) if the appropriate data are available.

---

[4] Five specific varieties of coal are discussed in this chapter. The IPCC definitions of these five varieties follow:
Anthracite: A hard, black, lustrous coal containing a high percentage of fixed carbon and a low percentage of volatile matter. Often referred to as hard coal.
Bituminous coal: A dense, black, soft coal, often with well-defined bands of bright and dull material. The most common coal, with moisture content usually less than 20 percent. Used for generating electricity, making coke, and space heating.
Lignite: A brownish-black coal of low rank with high inherent moisture and volatile matter content, used almost exclusively for electric power generation. Also referred to as brown coal.
Sub-bituminous coal: A dull, black coal of rank intermediate between lignite and bituminous coal.
Coal coke: A hard, porous product made from baking bituminous coal in ovens as temperatures as high as 2,000 degrees Fahrenheit. It is used as a fuel and as a reducing agent in smelting iron ore in a blast furnace.

Table 1.4-1 Worksheet to Calculate CO_2 Emissions from Fossil Fuels—Residential

	Input	Input	(A) × (B) ÷ 2000	Input	Input	[(C) - (D) - (E)] x Fraction Oxidized x 0.9072 Metric Tons/Ton
Sector/Fuel	(A) Consumption (10^6 Btu)	(B) Carbon Content Coefficient (lbs C/10^6 Btu)	(C) Total Carbon (tons C)	(D) Stored Carbon (tons C)	(E) International Bunkers (tons C)	(F) Net Carbon Emissions (metric tons C)
RESIDENTIAL						
Asphalt and Road Oil						
Aviation Gasoline						
Distillate Fuel Oil						
Jet Fuel: Kerosene Type						
Jet Fuel: Naphtha Type						
Kerosene						
Liquefied Petroleum Gas						
Lubricants						
Misc. Petroleum Products						
Motor Gasoline						
Naphtha						
Other Oil						
Pentane Plus						
Petroleum Coke						
Residual Fuel Oil						
Still Gas						
Waxes						
Anthracite Coal						
Bituminous Coal						
Sub-bituminous Coal						
Lignite Coal						
Coke						
Natural Gas						
RESIDENTIAL TOTAL						

Table 1.4-1 Worksheet to Calculate CO_2 Emissions from Fossil Fuels—Commercial

	Input	Input	(A) × (B) ÷ 2000	Input	Input	[(C) - (D) - (E)] x Fraction Oxidized x 0.9072 Metric Tons/Ton
Sector/Fuel	(A) Consumption (10^6 Btu)	(B) Carbon Content Coefficient (lbs C/10^6 Btu)	(C) Total Carbon (tons C)	(D) Stored Carbon (tons C)	(E) International Bunkers (tons C)	(F) Net Carbon Emissions (metric tons C)
COMMERCIAL						
Asphalt and Road Oil						
Aviation Gasoline						
Distillate Fuel Oil						
Jet Fuel: Kerosene Type						
Jet Fuel: Naphtha Type						
Kerosene						
Liquefied Petroleum Gas						
Lubricants						
Misc. Petroleum Products						
Motor Gasoline						
Naphtha						
Other Oil						
Pentane Plus						
Petroleum Coke						
Residual Fuel Oil						
Still Gas						
Waxes						
Anthracite Coal						
Bituminous Coal						
Sub-bituminous Coal						
Lignite Coal						
Coke						
Natural Gas						
COMMERCIAL TOTAL						

Table 1.4-1 Worksheet to Calculate CO_2 Emissions from Fossil Fuels—Industrial

	Input	Input	(A) × (B) ÷ 2000	Input	Input	[(C) - (D) - (E)] x Fraction Oxidized x 0.9072 Metric Tons/Ton
Sector/Fuel	(A) Consumption (10^6 Btu)	(B) Carbon Content Coefficient (lbs C/10^6 Btu)	(C) Total Carbon (tons C)	(D) Stored Carbon (tons C)	(E) International Bunkers (tons C)	(F) Net Carbon Emissions (metric tons C)
INDUSTRIAL						
Asphalt and Road Oil						
Aviation Gasoline						
Distillate Fuel Oil						
Jet Fuel: Kerosene Type						
Jet Fuel: Naphtha Type						
Kerosene						
Liquefied Petroleum Gas						
Lubricants						
Misc. Petroleum Products						
Motor Gasoline						
Naphtha						
Other Oil						
Pentane Plus						
Petroleum Coke						
Residual Fuel Oil						
Still Gas						
Waxes						
Anthracite Coal						
Bituminous Coal						
Sub-bituminous Coal						
Lignite Coal						
Coke						
Natural Gas						
INDUSTRIAL TOTAL						

Table 1.4-1 Worksheet to Calculate CO_2 Emissions from Fossil Fuels—Transportation

	Input	Input	(A) × (B) ÷ 2000	Input	Input	[(C) - (D) - (E)] x Fraction Oxidized x 0.9072 Metric Tons/Ton
Sector/Fuel	(A) Consumption (10^6 Btu)	(B) Carbon Content Coefficient (lbs C/10^6 Btu)	(C) Total Carbon (tons C)	(D) Stored Carbon (tons C)	(E) International Bunkers (tons C)	(F) Net Carbon Emissions (metric tons C)
TRANSPORTATION						
Asphalt and Road Oil						
Aviation Gasoline						
Distillate Fuel Oil						
Jet Fuel: Kerosene Type						
Jet Fuel: Naphtha Type						
Kerosene						
Liquefied Petroleum Gas						
Lubricants						
Misc. Petroleum Products						
Motor Gasoline						
Naphtha						
Other Oil						
Pentane Plus						
Petroleum Coke						
Residual Fuel Oil						
Still Gas						
Waxes						
Anthracite Coal						
Bituminous Coal						
Sub-bituminous Coal						
Lignite Coal						
Coke						
Natural Gas						
TRANSPORTATION TOTAL						

Table 1.4-1 Worksheet to Calculate CO_2 Emissions from Fossil Fuels—Electric Utilities

	Input	Input	(A) × (B) ÷ 2000	Input	Input	[(C) - (D) - (E)] x Fraction Oxidized x. 0.9072 Metric Tons/Ton
Sector/Fuel	(A) Consumption (10^6 Btu)	(B) Carbon Content Coefficient (lbs C/10^6 Btu)	(C) Total Carbon (tons C)	(D) Stored Carbon (tons C)	(E) International Bunkers (tons C)	(F) Net Carbon Emissions (metric tons C)
ELECTRIC UTILITIES						
Asphalt and Road Oil						
Aviation Gasoline						
Distillate Fuel Oil						
Jet Fuel: Kerosene Type						
Jet Fuel: Naphtha Type						
Kerosene						
Liquefied Petroleum Gas						
Lubricants						
Misc. Petroleum Products						
Motor Gasoline						
Naphtha						
Other Oil						
Pentane Plus						
Petroleum Coke						
Residual Fuel Oil						
Still Gas						
Waxes						
Anthracite Coal						
Bituminous Coal						
Sub-bituminous Coal						
Lignite Coal						
Coke						
Natural Gas						
ELECTRIC UTILITIES TOTAL						

Table 1.4-2 Factors to Convert Units to Million Btu[a]

Fuel Type	If data are in	Multiply by
Petroleum		
Asphalt and Road Oil	barrels	6.636
Aviation Gasoline	barrels	5.048
Distillate Fuel Oil	barrels	5.825
Jet Fuel: Kerosene Type	barrels	5.670
Jet Fuel: Naphtha Type	barrels	5.355
Kerosene	barrels	5.670
Liquefied Petroleum Gases	barrels	4.011
Lubricants	barrels	6.065
Miscellaneous Petroleum Products and Crude Oil	barrels	5.800
Motor Gasoline	barrels	5.253
Naphtha[b] and Special Naphthas	barrels	5.248
Other Oil[b] and Unfinished Oils	barrels	5.825
Pentane Plus	barrels	4.620
Petroleum Coke	barrels	6.024
Residual Fuel Oil	barrels	6.287
Still Gas[b]	barrels	6.000
Waxes	barrels	5.537
Coal[c]		
Anthracite[d]	short tons	21.668
Bituminous	short tons	23.89
Sub-bituminous	short tons	17.14
Lignite	short tons	12.866
Coal Coke	short tons	24.800
Natural Gas	billion cubic feet	$1.03 \times 1{,}000{,}000$
	Teracalories	3968

a. Heat contents of many fuels vary somewhat by source, year, and consumer. Except for coal and blended petroleum products, this variation tends to be relatively small. The values here are national averages for 1990.
b. By EIA definition, naphtha, other oil, and still gas are collectively termed petrochemical feedstocks.
c. Thermal conversion factors for coal can vary extensively by source. More complete state and sector specific factors are available through EIA.
d. The anthracite factor presented here is a national average. Actual anthracite factors could range from as low as 17.5 MMBtu/ton for anthracite reclaimed from refuse piles to 26 MMBtu/ton or higher for anthracite mined directly from the original seam.

Source: Petroleum and natural gas heat-equivalents are from EIA's *Annual Energy Review* (EIA 1997d). Coal heat-equivalents are from EIA's *State Energy Data Report* (EIA 1997c), *Cost and Quality of Fuels for Electric Utility Plants* (EIA 1997a), and *Quarterly Coal Report* (EIA 1997b).

Table 1.4-3: Carbon Content Coefficients for Fuel Combustion[a]
(lbs C/10^6 Btu)

Fuel Consumed	
Asphalt and Road Oil	45.5
Aviation Gas	41.6
Distillate Fuel Oil	44.0
Jet Fuel (all kinds)	43.5
Kerosene	43.5
Liquefied Petroleum Gas (LPG)	37.8
Lubricants	44.6
Motor Gasoline	42.8
Residual Fuel Oil	47.4
Misc. Petroleum Products and Crude Oil	44.7
Naphtha	40.0
Other Oil	44.0
Pentanes Plus	40.2
Petrochemical Feed	42.7
Petroleum Coke	61.4
Still Gas	38.6
Special Naphtha	43.8
Unfinished Oils	44.6
Waxes	43.7
Anthracite Coal	62.1
Bituminous Coal	56.0
Sub-bituminous Coal	57.9
Lignite Coal	58.7
Natural Gas	31.9

All coefficients are given as pounds of carbon emitted per million Btu of fuel consumed (lbs C/10^6 Btu). When multiplied by consumption in 10^6 Btu they result in emissions of carbon in pounds (lbs C).
a. Carbon content coefficients are sometimes called carbon coefficients.
Sources: Natural gas and petroleum coefficients are from U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1993*, except that coefficients for jet fuel, LPG, and motor gasoline are from EIA's *Emissions of Greenhouse Gases in the United States, 1996*. Coal coefficients are full combustion figures based on EIA's *Emissions of Greenhouse Gases in the United States: 1985-1990*.

- *Data Sources*. Any in-state sources, such as state energy commissions or public utility commissions, should be consulted first. Alternatively, state energy data by fuel type and sector for fossil fuels can be found in EIA's reports *State Energy Data Report* and *Coal Production*. These data are available on the Internet at http://www.eia.doe.gov/fueloverview.html#state .[5] Emission factors for coal by state of origin can also be used and can be found in the *Quarterly Coal Report* under Carbon Dioxide Emission Factors for Coal (Hong and Slatick, 1994). If using EIA's *State Energy Data Report*, note that the reported values for gasoline consumption from 1993 onward include ethanol fuel consumption. Because ethanol is a biofuel, carbon emissions from its combustion are not counted as greenhouse gas emissions. Thus, the gasoline values should be

[5] Note that the *State Energy Data Report* tables for state-by-state fuel consumption includes a category for "petroleum, other" under the industrial sector. This category includes petroleum coke. EIA can provide an extract from its database that lists, for a given state, the types and amounts of fuels that were combined in the "petroleum, other" category.

adjusted by subtracting the amount of ethanol fuel combustion. For users attempting to disaggregate the data further (*e.g.,* by specific end user, such as chemical manufacturers), there is currently no nationally published source providing this type of information. An appropriate source would need to be obtained at the state level to obtain these data.

- *Units for Reporting Data*. Fossil fuel statistics should also be provided on an energy basis (*i.e.,* million Btu). If fuel data are reported in other units and documented conversion factors cannot be obtained within the state, the conversion factors listed in Table 1.4-2 may be applied in order to convert to million Btu.

Example According to the EIA report *State Energy Data Report 1992*, total U.S. energy consumption of distillate fuel for the transportation sector in 1990 was 658 million barrels, which is equivalent to approximately 3.83×10^{15} Btu, or 3,832,850,000 million Btu as shown in the following calculation:

658,000,000 barrels $\times$ 5.825 million Btu/barrel = **3,832,850,000 million Btu**

Step (2) Estimate Total Carbon Content in Fuels (Table 1.4-1, Columns B and C)

Carbon content represents the total amount of carbon that could be emitted if 100 percent was released to the atmosphere. To estimate the total carbon that could be released from the fuels, multiply energy consumption for each fuel type by the appropriate carbon content coefficient. This calculation should be done for all fuel types in each sector.

Carbon content coefficients vary considerably both between and within the major fuel types, as noted below:

- For natural gas, the carbon content depends heavily on the composition of the gas, which includes methane, ethane, propane, other hydrocarbons, CO_2, and other gases. The relative proportions of these gases vary from one gas production site to another.

- For crude oil, Marland and Rotty (1984) suggest that the API gravity[6] indicates the carbon/hydrogen ratio. Carbon content per unit of energy is usually less for light refined products such as gasoline than for heavier products such as residual fuel oil.

- For coal, carbon emissions per ton vary considerably depending on the coal's composition of carbon, hydrogen, sulfur, ash, oxygen, and nitrogen. While variability of carbon emissions on a mass basis can be considerable, carbon

[6] Variations in petroleum are most often expressed in terms of specific gravity at 15 degrees C. The API gravity, where API gravity = 141.5/specific gravity - 131.5, is an indication of the molecular size, carbon/hydrogen ratio, and hence carbon content of a crude oil.

emissions per unit of energy (*e.g.*, per Btu) vary much less, with lower ranked coals such as sub-bituminous and lignites usually containing slightly more carbon than higher-ranked coals.

In general, carbon content coefficients are determined based on the composition and heat contents of fuel samples. Several studies have estimated carbon content coefficients for fossil fuels (Marland and Rotty, 1984; Marland and Pippin, 1991; Grubb, 1989; and others). Based on these studies and detailed fuel data, the Energy Information Administration of DOE estimates carbon content coefficients for a wide range of fuel types. Nationally averaged carbon content coefficients for each fuel type are listed in Table 1.4-3. As with thermal conversion factors, (1) these average carbon coefficients may not precisely reflect the carbon content of fuel used in a particular state or for years other than the years for which the coefficients were estimated, and (2) the degree of variation geographically and temporally is generally quite small for natural gas and refined petroleum fuels, but coal coefficients vary from mine to mine and year to year. Nationally averaged figures may be found in U.S. EPA (1998) and state factors may be found in DOE's *Electric Power Annual* (1997e). States are encouraged to use more detailed data if it is available and well documented.

The specific elements of this step are as follows:

- Table 1.4-3 presents default carbon content coefficients. If state-specific data are available and well-documented, they may be used in place of the values in Table 1.4-3. Multiplying fuel consumption by these coefficients yields potential emissions in pounds of carbon. The equations take the following form:

$$TC_i = C_i \times CCC_i$$

where: TC_i = Total carbon contained in fuel i (lbs C);
C_i = Fuel consumption for fuel i (10^6 Btu); and
CCC_i = Carbon content coefficient for fuel i (lbs C/10^6 Btu).

- For each fuel type, divide the results by 2000 lbs/ton to obtain tons of carbon.

- For each sector, sum the results of the fuel types to obtain the total carbon content in tons.

Example To calculate the total carbon content for distillate fuel in the U.S. transportation sector for the year 1990, obtain the result from Step 1 (3,832,850,000 million Btu of distillate fuel) and perform the following calculations:

(a) 3,832,850,000 million Btu $\times$ 44.0 lbs C/10^6 Btu = 168,645,400,000 lbs C
(b) 168,645,400,000 lbs C $\div$ 2000 lbs/ton = **84,322,700 tons C**

Step (3): Estimate Carbon Stored in Products (Table 1.4-1, Column D)

After estimating the total carbon contained in the fuels, the next step is to estimate the amount of carbon from these fuels that is sequestered in non-energy products for a significant period of time (*e.g.,* more than 20 years). All fossil fuels are used for non-energy purposes to some degree. For example, natural gas is used for ammonia production; LPG is used for production of solvents and synthetic rubber; oil is used to produce asphalt, naphthas, and lubricants; and coal is used to produce coke, yielding crude light oil and crude tar as by-products which are used in the chemical industry.

However, not all non-energy uses of fossil fuels result in carbon sequestration. For example, the carbon from natural gas used in ammonia production is oxidized quickly; many products from the chemical and refining industries are burned or decompose within a few years; and the carbon in coke is oxidized when the coke is used.

The approach used to determine the portion of carbon sequestered in products is based on that used by EIA (1997f), in which the following carbon storage assumptions can be made:

- *Coal (i.e., Coal Oil and Tars):* Based on Marland and Rotty (1984), approximately 6 percent of coal carbon entering coke plants is converted to coal oils and tars, of which 75 percent is sequestered and remains unoxidized for long periods of time.

- *Natural Gas:* The two main non-fuel uses of natural gas are for ammonia production in nitrogenous fertilizer manufacture, and as a chemical feedstock. It is assumed that 100 percent of the carbon in natural gas used as a chemical feedstock is sequestered. As noted above, the carbon from natural gas used in ammonia production is converted to CO_2 in the process, and is not sequestered.

- *LPG:* It is assumed that 80 percent of the carbon in LPG sold for chemical and industrial uses is sequestered in products.

- *Asphalt and Road Oil (i.e., Bitumen):* It is assumed that 100 percent of the carbon in these products is sequestered indefinitely.

- *Lubricants:* Of the carbon contained in lubricants (*e.g.,* automotive oil, grease, etc.), approximately 50 percent is assumed to remain unoxidized for long periods of time.

- *Petrochemical Feedstocks:* This category includes naphthas and other petroleum products used as chemical feedstocks in petroleum related industries. Seventy-five percent of the carbon in this category is assumed to end up in products such as plastics, tires, and fabrics, which sequester carbon over long periods of time.

- *Waxes and Miscellaneous Products:* This category, as defined by EIA, includes waxes and various other petroleum products used for non-fuel purposes. Until more exact information is available, 100 percent of the carbon contained in these products is assumed to be sequestered. For example, the carbon contained in waxes for food industry wrappers is assumed to be sequestered in landfills.

These assumptions are reflected in the default values recommended in Table 1.4-4. As more detailed information on non-fuel uses of fossil fuels becomes available, estimates of the fraction of carbon stored may change. States should use the most up-to-date information available, and document their assumptions.

Using the carbon sequestration percentages listed in Table 1.4-4, the suggested approach for estimating carbon sequestered in products for each state starts with the following basic equation:

$$CS_i = U_i \times CCC_i \times FS_i$$

where: CS_i = Carbon Sequestered in product i (lbs of carbon);
U_i = Non-fuel use of energy for product i (million Btu);
CCC_i = Carbon Content Coefficient for product i (lbs C / million Btu);
and
FS_i = Fraction of carbon in product i which is Sequestered.

Total carbon sequestered in products can be determined by summing CS_i over the various products. The resulting carbon sequestration estimates from non-energy uses of fossil fuels are subtracted (in Step 6) from the total emissions of carbon. When estimating emissions sector-by-sector, it is suggested that sequestered carbon from products be assigned to the industrial sector, unless justification for allocating certain products to another sector can be clearly demonstrated.

Once adjustments have been made to state totals for carbon sequestered (and emissions from international bunker fuel consumption, if the data are available), the resulting figure is the "Net Carbon Content," or "Net Potential Carbon Emissions."

The specific elements of this step are as follows:

- For each fuel type that has non-fuel uses (as listed in Table 1.4-4), estimate the quantity of fuel consumed in non-fuel uses, based on (1) the total amount consumed and (2) the fraction consumed for non-fuel uses. Data on the quantity of each fuel type consumed may be obtained as described in Step 1 above. For data on the fraction of each fuel type consumed for non-fuel uses, in-state sources, such as state energy commissions or public utility commissions, should be consulted first. Otherwise, estimates of the national-level fraction of each fuel type used for non-fuel uses can be determined using the U.S. DOE/EIA reports *Annual Energy Review* and *State Energy Data Report*, and the national fractions may be used as a proxy for the state fractions.

- Calculate the carbon content of fuels consumed in non-fuel uses by multiplying the non-fuel use quantities by their respective carbon content coefficients in Table 1.4-3.

- Estimate the fraction of carbon in each fuel which is stored for a long period of time (*i.e.*, 20 years or more). National default values are given in Table 1.4-4. However, state-level fractions may differ depending on the type of non-fuel uses. Thus, where state-specific estimates are available, their use is preferred; such estimates should be presented with adequate supporting documentation.

Table 1.4-4: Percent of Carbon Stored by Non-fuel Uses[a]

Fuel Type	Percentage Stored
Coal Oils and Tars from coke production	75%
Natural Gas as a chemical feedstock	100%
Asphalt and Road Oil	100%
LPG (Liquefied Petroleum Gas)	80%
Lubricants	50%
Petrochemical Feedstocks	75%
Waxes and Miscellaneous Products	100%

a. See discussion under Step 3 for assumptions on which these values are based.
Sources: Values for coal oil and tars, asphalt and road oil, LPG, and lubricants are from Marland and Rotty (1984). The value for natural gas is from communication with EIA (Rypinski, 1994). The values for petrochemical feedstocks and waxes and miscellaneous products are from EIA (EIA 1997f).

Example To calculate the amount of LPG used for non-fuel purposes in Wisconsin in 1994, based on national-level non-fuel usage, obtain (1) state-level data for LPG consumption in Wisconsin's industrial sector, from Table 314 of the *State Energy Data Report*, (2) national-level data for LPG used for non-fuel purposes, from Table 1.15 of the *Annual Energy Review*, and (3) national-level data for total LPG consumption in the industrial sector, from Table 14 of the *State Energy Data Report*. Then perform the following calculations:

a) Amount of LPG consumed in Wisconsin's industrial sector in 1994: 8,100,000 million Btu

b) Amount of LPG used for non-fuel purposes nationwide in 1994: 1,800,000,000 million Btu

c) Amount of LPG consumed nationwide in 1994: 1,996,500,000 million Btu

d) National-level fraction of LPG used for non-fuel uses:

$$1{,}800{,}000{,}000 \div 1{,}996{,}500{,}000 = 0.90$$

e) Estimated amount of LPG used for non-fuel uses in Wisconsin in 1994:

$$8{,}100{,}000 \text{ million Btu} \times 0.90 = 7{,}300{,}000 \text{ million Btu}$$

- Calculate the carbon stored by multiplying the carbon content of non-fuel uses by the fraction stored.

- Enter the resulting values in Column D of Table 1.4-1. These values are eventually subtracted from total carbon potentially emitted (Table 1.4-1, Column C).

Example To calculate the amount of carbon stored from LPG used for non-fuel purposes in Wisconsin in 1994, perform the following calculations:

a) 7,300,000 million Btu × 37.8 lbs C/10^6 Btu = 275,940,000 lbs C

b) 275,940,000 lbs C ÷ 2000 lbs/ton = 137,970 tons C

c) 137,970 tons C × 0.80 = **110,376 tons C stored**

Step (4): Estimate Carbon from Bunker Fuel Consumption (Table 1.4-1, Column E)

“International bunker fuels” and “domestic bunker fuels” are fuels used in international and interstate transportation, respectively.

International bunker fuel is fuel which originates in a state, but is supplied to ships and aircraft which consume it during international transport activities. For example, distillate fuel, residual fuel, and jet fuel may be sold in a state and be consumed outside the U.S. Because this fuel is not combusted solely in the U.S., its emissions cannot be clearly attributed to the U.S. In accordance with international inventory practices (IPCC, 1997), if state-level data are available, emissions from international bunkers may be calculated and reported by the state of origin, but not included in the state's total emission figures. In this way, emissions from these sources can be quantified without attributing undue emissions to the U.S. or any state therein.

Domestic bunkers include fuel supplied to vehicles (aircraft, autos, ships, etc.) for use in interstate transportation. Since it is extremely difficult to obtain accurate activity data on interstate transportation, there is currently no method to determine emissions from domestic bunker fuel consumption. Since general emissions calculations are based on consumption, all emissions from interstate transportation will be captured by those calculations. Therefore, domestic bunkers should not be specifically addressed.

Emissions from international and domestic bunker fuels are typically not addressed in state emission inventories, due to difficulties in obtaining the necessary data. (For example, the US Department of Energy’s *State Energy Data Report* does not provide data on bunker fuels.) However, if a state collects data on emissions from either or both types of bunker fuels, the state may estimate emissions from bunker fuels. Then, in Step (6) of this methodology, estimated emissions from bunker fuels would be subtracted from the estimated emissions from all fuel consumption. Note that the subtraction of bunker fuel consumed in international transportation is consistent with international greenhouse gas reporting guidelines developed by the Intergovernmental Panel on Climate Change (IPCC, 1997).

This step outlines the procedure for estimating consumption of international bunker fuel (if data are available). If data are available for domestic bunker fuel, a similar approach could be used to estimate carbon emissions from consumption of domestic bunker fuel.

- International bunker fuel emissions are calculated in the same manner as other emissions from fossil fuel combustion. Once consumption of international bunker fuels is determined, they are multiplied by their appropriate carbon content coefficients (see Table 1.4-3). This results in the amount of carbon potentially emitted by combustion of these fuels, or total carbon contained in the fuels, as shown in the equation below:

$$TC_i = C_i \times CCC_i$$

where: TC_i = Total Carbon contained in bunker fuel i (pounds);
C_i = Consumption of bunker fuel i (million Btu); and
CCC_i = Carbon Content Coefficient for bunker fuel i (lbs C / million Btu)

- The total carbon contained in each bunker fuel should be entered in Column E of Table 1.4-1. These values should be subtracted from total carbon (Column C of Table 1.4-1) *only* if international bunkers have been captured in the total carbon figures. If the carbon values in Column C do not include international bunker fuels, then the values in Column E should not be deducted.

Example At the national level, distillate fuel oil used for international bunkers is obtained from U.S. DOE/EIA *International Energy Annual*. The 1990 figure for the U.S. and its territories is 19,345,000 barrels. The following calculations are performed to compute carbon in distillate fuel used for international bunkers:

(a) 19,345,000 barrels × 5.825 million Btu/barrel = 112,685,000 million Btu

(b) 112,685,000 million Btu × 44.0 lbs C/million Btu = 4,958,140,000 lbs C

(c) 4,958,140,000 lbs C ÷ 2000 lbs/ton = **2,479,070 tons C**

Step (5): Calculate Net Potential Carbon Emissions (Table 1.4-1, Column F)

- Subtract the carbon stored (Table 1.4-1, Column D) and, if necessary, the carbon emitted from bunker fuel consumption (Table 1.4-1, Column E) from the total carbon (Table 1.4-1, Column C).

- The resulting value represents the net potential carbon emissions, and is the first factor used in calculating the value in Column F of Table 1.4-1.

Example	At the national level the carbon content of LPG consumed in the U.S. is approximately 30,400,000 tons carbon, the amount stored in non-fuel uses is about 19,400,000 tons carbon, and there is no consumption of LPG for international bunkers. To calculate the net potential carbon emissions of LPG combusted in the industrial sector perform the following calculation (using state-level data): 30,400,000 ton C - 19,400,000 ton C stored - 0 ton C bunkers = **11,000,000 ton C**

Step (6): Estimate Carbon Oxidized from Energy Uses (Table 1.4-1, Column F)

As described earlier, not all carbon is oxidized during the combustion of fossil fuels. The amount of carbon that does not oxidize during combustion is usually a small fraction of total carbon, and of this amount a large portion oxidizes in the atmosphere shortly after combustion. The remaining unoxidized carbon is sequestered in soot or ash. Based on EIA (1997f), the following factors are recommended:

- For natural gas, less than 0.5 percent of the carbon is unoxidized during combustion and remains as soot or ash in the burner, stack, or in the environment. (This is equivalent to a fraction oxidized of 0.995.)

- For petroleum fuels, approximately 1 percent is sequestered as soot or ash. (This is equivalent to a fraction oxidized of 0.99.)

- For coal, approximately 1 percent of carbon is sequestered, primarily as ash. (This is equivalent to a fraction oxidized of 0.99.)[7]

These values vary based on fuel quality and type of combustion technology (particularly for coal). If values are available for state level combustion, they should be used and documented.

The specific elements of this step are as follows:

- Use the values for fraction oxidized as the second factor in calculating the value in Column F of Table 1.4-1.

- Multiply the first factor (net carbon content for each fuel and sector) by the second factor (fraction of carbon oxidized) to obtain the total amount of carbon oxidized to carbon dioxide from the combustion of the fuel. This calculation will take the following form:

$$\text{Net Carbon Content (tons)} \times \text{Fraction Oxidized} = \text{Total Oxidized Carbon (tons C)}$$

[7] The Intergovernmental Panel on Climate Change recommends using a value of 0.98 for the fraction of coal oxidized. However, the US Department of Energy recommends using a value of 0.99, because coal combustors in the US achieve more complete combustion than the global average reflected in the IPCC value.

- Sum the results to obtain the total amount of carbon oxidized from all fuel types.

Example	To calculate the total amount of carbon oxidized from the combustion of LPG in the U.S. industrial sector perform the following calculation, where the net carbon content of industrial LPG is about 11,000,000 ton C: 11,000,000 tons C × 0.99 = **10,890,000 tons C**

Step (7): Convert to Total Carbon Equivalent Emissions from Energy Consumption (Table 1.4-1, Column F)

- Use the ratio of metric tons per short ton (0.9072) as the third factor in calculating the value in Column F of Table 1.4-1.

- Multiply the product of the first two factors (Total Carbon Oxidized) for each fuel and sector by 0.9072 to obtain total carbon equivalent emissions, measured in metric tons, and enter the value in Column F of Table 1.4-1.[8]

- Sum across each fuel and each sector to find total state emissions of CO_2 from energy consumption (again, measured in metric tons of carbon).

Example	To convert the units for the amount of carbon emitted due to LPG consumption (10,890,000 tons C) to metric tons, perform the following calculation: 10,890,000 tons C × 0.9072 metric tons/ton = **9,910,000 metric tons carbon**

Summary

The steps above provide estimates of total carbon in fossil fuels consumed, carbon sequestered in non-energy products, and proportion of carbon oxidized to CO_2. Given these estimates, total carbon emissions from fossil fuel combustion can be determined. Total carbon emissions are equal to the total carbon content in fuel, minus carbon sequestered in products (and emissions from international bunkers if estimated), adjusted for the carbon unoxidized during combustion, and summed over all fuel types.

[8] Note that the EPA report *State Workbook: Guidance for Estimating Greenhouse Gas Emissions* (the predecessor of the EIIP documents) expressed results in short tons of CO_2 equivalent. This EIIP volume uses units of metric tons of carbon equivalent, so that results will be expressed in the same units as are used in the US greenhouse gas inventory.

5

SUPPLEMENTAL METHODS FOR ESTIMATING EMISSIONS

The preferred method outlined above in Section 4 accounts for all fossil fuel combusted in a state, including the fuel used to generate electricity. However, electricity is often produced in one state for consumption in another (*i.e.*, fuel may be used in one state to generate electricity that is sent across power lines to be consumed in another state). The emissions from electricity consumption, however, occur in the generating state. For consistency, each state should count the CO_2 emissions from all electricity generation in the state, regardless of where the electricity is ultimately used. However, emission estimates for net imports may be useful in analyzing strategies to reduce emissions. For example, states may choose to implement energy efficiency measures; these measures relate to energy consumption, not generation. For this reason, states are encouraged to estimate the CO_2 emissions associated with electricity consumption in the state. To do so, a state will need to sum (a) the CO_2 emissions from electricity generation (estimated using the method in section 4), plus (b) the CO_2 emissions from net imports of electricity (estimated using one of the two methods described below). If a state exports more electricity than it imports, it will have negative net imports, and negative CO_2 emissions from net imports. In such a case, the state's CO_2 emissions from electricity consumption will be less than its emissions from electricity generation.

Section 5.1 below presents two alternative methods for estimating the CO_2 emissions from net imports of electricity. Section 5.2 below shows how to sum (a) the CO_2 emissions from electricity generation, plus (b) the CO_2 emissions from net imports of electricity.

5.1 ESTIMATE CO_2 EMISSIONS FROM NET IMPORTS OF ELECTRICITY

This section presents two alternative methods for estimating the CO_2 emissions from net imports of electricity. The first method uses national average CO_2 emission rates for electricity generation, while the second uses state-specific CO_2 emission rates for electricity imported and exported from the state. The first approach is easier to use. The second is more accurate, because it reflects the mix of fuels used to generate electricity that is imported into or exported from a state. Note that neither approach attempts to determine which type (or mix) of fuel is the marginal fuel used by utilities to generate the electricity that is exported to another state. Using CO_2 emission rates for the marginal fuel would result in the most accurate estimate, but at this time no methodology (complete with data sources) has been developed for such an approach.

Method A: Estimate Carbon Emissions from Net Imports of Electricity Using National Average Carbon Coefficient for Electricity Generation

If emissions were distributed across end-use consumers, net imports would result in an increase in state emission totals, because they represent additional fossil fuel consumption attributable to end-users within the state. Net exports would result in a decrease in state totals, because it represents fuel consumed in state to produce energy used by out of state consumers.

The specific elements of this method are as follows:

- Estimate the state's *net imports* of electricity (i.e., imports minus exports). Data from which imports and exports of electricity may be calculated are available in two EIA reports – *Electric Power Annual* (which reports net generation by utilities in each state, and retail sales to end users in each state) and *Annual Energy Review*. Because of losses in transmission and distribution of electricity between the point of generation and the point of use by the end user, a state analyst must adjust the retail sales figure to determine the amount of generation that was required to meet the retail sales demand. To do so, first determine the national average rate of losses during transmission and distribution from the *Annual Energy Review*'s table "Electricity Overview" (Table 8-1 in the 1996 edition). Specifically, divide the value in that table for the most recent year's "Losses and Unaccounted For" by the value for the most recent year's "Total Net Generation." In 1996, the resulting loss rate was 8 percent. Next, obtain the value for the state's retail sales for the most recent year, from the appropriate table in *Electric Power Annual* (Table 23 in the 1996 edition). Then scale up the value for retail sales by a factor of (1/(1-loss rate)) to determine the amount of generation required to meet the state's retail sales demand. Finally, to determine net imports, subtract that value, for the state's required generation, from the value for the state's net utility generation, from the appropriate table in *Electric Power Annual* (Table 9 in the 1996 edition). Data on net imports should be reported in kilowatt-hours.

- Obtain data for the U.S. national average emissions of carbon (in pounds) per kilowatt-hour of electricity generated. For 1995, this value was 0.36 pounds of carbon per kilowatt-hour of electricity generated.[9]

- The following equation summarizes the steps outlined above:

$$\text{ENI} = \text{NetImp} \times \text{CCC}$$

where:

ENI	=	Emissions of carbon due to net imports (lbs carbon);
NetImp	=	Net electricity imports, i.e., imports minus exports (kwh) [if exports exceed imports, the value for "NetImp" will be negative];
CCC	=	National average Carbon Content Coefficient for electricity generated (lbs carbon /kwh).

[9] Sources: EIA, *Emissions of Greenhouse Gases in the United States 1996 (Draft)*, (EIA 1997f), and EIA, *Electric Power Annual 1996* (EIA 1997e).

- Convert the resulting value to units of metric tons of carbon equivalent (MTCE). To do so, first divide the number of pounds of carbon by 2,000, to obtain the number of short tons of carbon. Then multiply the number of short tons of carbon by 0.9072, to obtain the number of metric tons of carbon. Because this carbon represents CO_2, the number of metric tons of carbon is also the number of MTCE.

Method B: Estimate Carbon Emissions Associated with Net Imports of Electricity Using National Average Carbon Coefficient for Electricity Generation

This method, provided by the California Energy Commission, has been developed and applied by the Commission to estimate the carbon emissions resulting from power transactions with electricity utilities located outside of California. The method uses data from the U.S. Department of Energy's Energy Information Administration (EIA) to (1) determine the overall carbon emission factor for each utility involved with transmitting power across a state's borders, (2) determine the amount of power transmitted, (3) estimate the corresponding carbon emissions, and (4) convert from units of tons of carbon to units of metric tons of carbon equivalent (MTCE). The carbon emission factor for each utility is a description of the resources that that utility used to generate all the power required for all their customers. The EIA Bulk Power Transaction database contains all the power transactions between utilities in the United States (and may also include some information on Mexico and Canada). Isolating only those transactions that involved out-of-state[10] utilities, and multiplying those transaction amounts by the overall carbon emission factor will yield the out-of-state carbon emissions.

This method makes the assumption that a utility that exports electricity to another state does so using its total available resource mix, rather than any particular power plant or group of plants.

Example

Table 1.5-1 presents the carbon emission factors for a fictitious utility that has four power plants: a coal fired boiler, a nuclear power plant, a hydroelectric plant, and a gas fired combustion turbine. We assume that the carbon content is 55.4 lbs/MMBtu for coal and 31.7 lbs/MMBtu for natural gas, and that both the thermal power plants have a heat rate of 10,000 Btu/kWh. With the given generation data and the assumption noted above, it is possible to determine the carbon emissions for each fuel/technology type. From this information it is very simple to determine the overall carbon emission factor for the utility by summing the carbon emissions across the four plants and dividing by the total generation. If the generation data were not available, then it would be necessary to estimate the carbon emission factor by using the capacities and heat rates of the power plants. Using the example in Table 1.5-1, that estimate would be developed as follows:

[1,000 (MW) $\times$ 55.4 (lbs/MMBtu) $\times$ 10,000 (MMBtu/GWH) $\div$ 2000 (lbs/Ton) + 300 (MW) $\times$ 31.7 (lbs/MMBtu)) $\times$ 10,000 (MMBtu/GWH) $\div$ 2000 (lbs/Ton)] $\div$ 2,800 (MW) = 115.91 (Tons/GWH)

[10] In general this means any utility not primarily located in the state of interest. Note that many utilities own power plants in several states.

TABLE 1.5-1
Hypothetical 1994 Utility Data

Fuel-Technology Type	Capacity (MW)	1994 Generation (GWH)	Carbon Emissions (Tons)	Power Profile (%)	Emission Profile (%)
Coal	1,000	2,000	554,000	20%	77.75%
Nuclear	1,000	4,000	0	40%	0%
Hydroelectric	500	3,000	0	30%	0%
Natural Gas	300	1,000	158,500	10%	22.25%
Total	2,800	10,000	712,500	100%	100%

Overall Carbon Emission Factor: 71.25 Tons/GWH by generation
Overall Carbon Emission Factor: 115.91 Tons/GWH by capacity

Procedure

This section lists the steps for employing this method. When using this method, it is a good practice to carefully record your assumptions.

1 Acquire the EIA Monthly Power Plant Report (Form 759), Annual Electric Generator Report (Form 860) and Bulk Power Transaction databases (mainly Form 412) for the year of interest. They are available from EIA's Internet site, or by contacting the form manager directly.[11] Note, however, that pending changes in the confidentiality regulations may make these reports inaccessible, starting with the 1999 data.

2 Using a database manager (e.g., dBase for Windows, Paradox, etc.) manipulate this information to determine what utilities are important to the state in question. The data bases included in the Bulk Power Transaction database are (1) purchases, (2) sales, (3) exchanges, (4) wheeled power and (5) company identifications. Note that the company identifications provide the location for the headquarters, not necessarily the power plants.

  2.1 By whatever means are available, verify which utilities are located in-state, taking into account those power plants located out-of-state but owned by in-state utilities.

  2.2 Identify those transactions between in-state and out-of-state utilities. These will include specifically identified utilities, power pools and aggregated purchases.

3 Calculate, for those utilities identified, the carbon emission factor in units of pounds carbon per gigawatt-hour (GWH). Use one of the methods described below to determine the carbon emission factors. The methods are arranged in order of preference.

  3.1 Monthly Power Plant Report (EIA Form 759)

[11] For data on bulk power transactions, contact John Makens at (202) 426-1165. For data from the Monthly Power Plant Report (Form 759), contact Melvin Johnson at (202) 426-1172. For data from the Annual Electric Generator Report (Form 860), contact Stephen Calopedis at (202) 426-1143.

3.1.1 Using the 759 database, develop for all power plants of each utility identified separate summations for (1) the monthly power generation (note that the units change from MWH to GWH between 1990 to 1995) and (2) fuel use (units will be in barrels, cubic feet or tons).

3.1.2 Using the same method as in section 4 of this chapter, convert the fuel use first to units of million BTUs, and then to pounds of carbon emitted. (Other sources of heat content for fuels include the EIA State Energy Data Report for 1995, Appendix D, and Appendix G for CO_2 emissions from coal fired power plants.)

3.1.3 Divide the pounds of carbon by the total generation to obtain the carbon emission factor for the utility.

3.2 Annual Electric Generator Report (Form 860) [for utilities not in 759]

3.2.1 Database 860 does not identify electricity production or fuel use, but it does provide data on capacities and heat rates. As for 759, segregate power plants for the utilities identified.

3.2.2 Ensure that for each segregated power plant, Database 860 provides data for capacity and heat rate. For missing capacities, refer to other documents, such as Electrical World's *Directory of Electric Power Producers and Distributors* (Electrical World 1999). For missing heat rates, proceed with the following in the order suggested:

3.2.2.1 Substitute into 860, by fuel/prime mover type, the heat rates identified in Table 1.5-2 for those power plants that do not have a heat rate value.

3.2.2.2 Substitute into 860 a heat rate of 10,000 Btu/kWh for those power plants that do not have a heat rate.

3.2.3 Convert the heat rate into a carbon emission factor using the method in section 4 of this chapter [i.e., $CEF_{Power\ Plant}$ {lbs C/kWh} = HR {Btu/kWh} $\times$ CCC {lbs C/MMBtu} $\times$ 10^{-6} {MMBtu/Btu}].

3.2.4 Sum the carbon emission factor times the capacity and the capacity alone for each power plant within a utility. Divide the carbon emission rate $\times$ capacity summation by the capacity summation to determine the utility's overall carbon emission factor [i.e., $CEF_{Utility} = \sum(CEF_{Power\ Plant} \times \text{Capacity}) \div \sum\text{Capacity}$].

3.3 For utilities not listed in either 759 or 860, try the following references:

3.3.1 Electric World's Directory of Utilities

3.3.2 The Western Systems Coordination Council Bulk Power Supply Program

3.4 If these, and other, references fail, then the utilities in question do not represent a large portion of the out-of-state power transactions. Thus, you may use expert judgment to estimate their carbon emission factors.

4 Once you have determined the carbon emission factors for each utility, or have appropriate assumptions in place, it is a simple matter to multiply the power transactions by the carbon emission factors to determine the carbon emissions from out-of-state power transactions.

5 Convert the units. Multiply the number of tons of carbon by 0.9072 to obtain the number of metric tons of carbon. Because this carbon is in the form of CO_2, the number of metric tons of carbon is also the number of metric tons of carbon equivalent (MTCE).

The results of this type of analysis for California are presented in the appendix to this chapter.

5.2 SUM CO_2 FROM ELECTRICITY GENERATION AND CO_2 FROM NET IMPORTS OF ELECTRICITY

To estimate the CO_2 emissions from electricity consumption in a state, the emissions from net imports of electricity (estimated as described in section 5.1) must be added to the emissions from electricity generation (estimated as described in section 4). Because this is a simple summation of two values expressed in the same units (i.e., MTCE), no example calculation is provided.

Table 1.5-2
Average Heat Rates for Fuel Types and Prime Movers

Fuel type and Prime Mover	Heat Rate (Btu/kWh)
Coal	
Anthracite	
Steam Turbine (Boiler)	11,792
Bituminous	
AB	12,858
Steam Turbine (Boiler)	9,941
Generic	
Steam Turbine (Boiler)	13,671
Lignite	
AB	11,039
Steam Turbine (Boiler)	10,933
Sub-Bituminous	
Steam Turbine (Boiler)	10,354
Fuel Oil	
No. 1 Fuel Oil	
Gas Turbine	48,138[†]
Internal Combustion	11,672
Jet Engine	16,415
No. 2 Fuel Oil	
Combined Cycle Combustion Turbine	12,420
Gas Turbine	14,085
Internal Combustion	10,847
Jet Engine	13,406
Steam Turbine (Boiler)	8,653
No. 4 Fuel Oil	
Gas Turbine	10,180
Internal Combustion	9,695
Steam Turbine (Boiler)	11,524
No. 5 Fuel Oil	
Internal Combustion	11,404
No. 6 Fuel Oil	
Internal Combustion	8,935
Steam Turbine (Boiler)	10,453

Table 1.5-2 (Continued)
Average Heat Rates for Fuel Types and Prime Movers

Fuel type and Prime Mover	Heat Rate (Btu/kWh)
Natural Gas	
Pipe Line Grade Natural Gas	
Combined Cycle Steam Turbine w/ Sup. Firing	10,229
Combined Cycle Single Shaft	8,952
Combined Cycle Combustion Turbine	11,648
Gas Turbine	13,918
Internal Combustion	10,538
Jet Engine	16,271
Steam Turbine (Boiler)	10,502
Non-Combustion	
Geothermal Steam	
Geothermal Steam Turbine	19,162
Uranium	
Steam Turbine (Boiling Water Nuclear Reactor)	10,575
Steam Turbine (High-Temperature Gas-Cooled	11,500
Steam Turbine (Pressurized Water Nuclear Reactor)	10,479
Water	
Hydraulic Turbine (conventional)	11,467
Waste Heat	
Combined Cycle Steam Turbine w/ Sup. Firing	9,238
Combined Cycle Combustion Turbine	7,687
Combined Cycle Steam Turbine Waste Heat Boiler	9,208

Table 1.5-2 (Continued)
Average Heat Rates for Fuel Types and Prime Movers

Fuel type and Prime Mover	Heat Rate (Btu/kWh)
Other Liquid Fuel	
Jet Fuel	
Gas Turbine	13,384
Jet Engine	13,021
Kerosene	
Gas Turbine	15,393
Jet Engine	14,195
Liquefied Propane Gas	
Gas Turbine	13,503
Steam Turbine (Boiler)	14,200
Methanol Fuel	
Internal Combustion	9,517
Other Solid Fuel	
Petroleum Coke	
Steam Turbine (Boiler)	10,374
Refuse, Bagasses, non-wood	
Internal Combustion	15,000
Steam Turbine (Boiler)	13,706
Wood and Wood Waste	
Steam Turbine (Boiler)	15,725
Other Vapor Fuel	
Blast Furnace Gas	
Steam Turbine (Boiler)	9,215
Refinery Gas	
Gas Turbine	15,000
Internal Combustion	14,000
Synthetic Natural Gas	
Combined Cycle Combustion Turbine	11,100

All data are averaged from the Department of Energy, Energy Information Administration EIA-Form 860, "Annual Electric Generator Report, 1992."

† This exceedingly high heat rate represents one power plant (Danbury Dam, Northwest Wisconsin Electric Co.), and is most likely a transcription an error. However, since there are no purchases, sales, exchanges or wheeled purchases from this utility by any California utility, then we choose not to attempt to correct this value.

6

QUALITY ASSURANCE/QUALITY CONTROL

Quality assurance (QA) and quality control (QC) are essential elements in producing high quality emission estimates and should be included in all methods to estimate emissions. QA/QC of emissions estimates are accomplished through a set of procedures that ensure the quality and reliability of data collection and processing. These procedures include the use of appropriate emission estimation methods, reasonable assumptions, data reliability checks, and accuracy/logic checks of calculations. Volume VI of this series, *Quality Assurance Procedures*, describes methods and tools for performing these procedures.

6.1 DATA ATTRIBUTE RANKING SYSTEM (DARS) SCORES

DARS is a system for evaluating the quality of data used in an emission inventory. To develop a DARS score, one must evaluate the reliability of eight components of the emissions estimate. Four of the components are related to the activity level (e.g., the amount of fossil fuel combusted), and the other four are related to the emission factor (e.g., the amount of CO_2 emitted per unit of fossil fuel combusted). For both the activity level and the emission factor, the four attributes evaluated are the measurement method, source specificity, spatial congruity, and temporal congruity. Each component is scored on a scale of zero to one, where one represents a high level of reliability. To derive the DARS score for a given estimation method, the activity level score is multiplied by the emission factor score for each of the four attributes, and the resulting products are averaged. The highest possible DARS composite score is one. A complete discussion of DARS may be found in Chapter 4 of Volume VI, *Quality Assurance Procedures*.

The DARS scores provided below are based on the use of the emission factors provided in this chapter, and activity data from the US government sources referenced in the various steps of the methodology. Separate scores are provided for each of the key fuels. If a state uses state data sources for activity data for one or more fossil fuels, the state may wish to develop its own DARS scores for those fossil fuels, based on the use of state data.

TABLE 1.6-1

DARS SCORES: CO_2 EMISSIONS FROM GASOLINE COMBUSTION

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	9	The emission factor is based on a precise stoichiometric relationship.	9	Fuel purchases are measured using top-down statistics; states may have better data from tax records.	0.81
Source Specificity	10	The emission factor was developed specifically for gasoline combustion.	9	Fuel purchases are very closely correlated to the emissions process.	0.90
Spatial Congruity	9	U.S. emission factors are used, but the carbon coefficient for gasoline varies depending on its source.	9	States use state-level activity data to estimate state-wide emissions.	0.81
Temporal Congruity	9	The emission factor is based on stoichiometry, not on measured emissions over a particular time frame. However, the emission factor should not vary significantly over the course of a year.	10	States use annual activity data to estimate annual emissions.	0.90
				Composite Score	**0.86**

Note 1: The DARS scores for gasoline are used as a benchmark for determining DARS scores for other fuels.
Note 2: This inventory estimates gasoline emissions from the point of sale. The spacial DARS score would be lower if emissions were estimated based on VMT.

TABLE 1.6-2

DARS SCORES: CO_2 EMISSIONS FROM DISTILLATE FUEL OIL COMBUSTION

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	9	The emission factor is based on a precise stoichiometric relationship.	9	Fuel purchases are measured using top-down statistics.	0.81
Source Specificity	9	The emission factor was developed specifically for distillate fuel oil combustion.	9	Fuel purchases are very closely correlated to the emissions process.	0.81
Spatial Congruity	9	U.S. emission factors are used, but the carbon coefficient for distillate fuel oil varies slightly depending on its source.	8	States use state-level activity data to estimate state-wide emissions, but there are minor cross-state sales by retailers.	0.72
Temporal Congruity	9	The emission factor is based on stoichiometry, not on measured emissions over a particular time frame. However, the emission factor should not vary significantly over the course of a year.	9	States use annual activity data to estimate annual emissions.	0.81
				Composite Score	**0.79**

TABLE 1.6-3

DARS SCORES: CO_2 EMISSIONS FROM RESIDUAL FUEL OIL COMBUSTION

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	9	The emission factor is based on a precise stoichiometric relationship.	9	Fuel purchases are measured using top-down statistics.	0.81
Source Specificity	8	The emission factor was developed specifically for residual fuel oil combustion, but residual fuel can be more or less dense, depending on how the refinery is run.	9	Fuel purchases are very closely correlated to the emissions process.	0.72
Spatial Congruity	8	U.S. emission factors are used, but the carbon coefficient for residual fuel varies slightly depending on its source.	9	States use state-level activity data to estimate state-wide emissions.	0.72
Temporal Congruity	8	The emission factor is based on stoichiometry, not on measured emissions over a particular time frame. However, the emission factor may vary over the course of a year.	9	States use annual activity data to estimate annual emissions.	0.72
				Composite Score	**0.74**

TABLE 1.6-4

DARS SCORES: CO_2 EMISSIONS FROM COMBUSTION OF JET FUEL: KEROSENE TYPE

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	9	The emission factor is based on a precise stoichiometric relationship.	9	Fuel purchases are measured using top-down statistics.	0.81
Source Specificity	10	The emission factor was developed specifically for jet fuel combustion.	9	Fuel purchases are very closely correlated to the emissions process.	0.90
Spatial Congruity	9	U.S. emission factors are used, but the carbon coefficient for jet fuel varies slightly depending on its source.	7	States use state-level activity data to estimate state-wide emissions. However, jet fuel is generally not burned where it is bought.	0.63
Temporal Congruity	10	The emission factor is based on stoichiometry, not on measured emissions over a particular time frame. However, jet fuel is a relatively homogenous product, and the emission factor should not vary over the course of a year.	10	States use annual activity data to estimate annual emissions, and jet fuel is typically combusted in the year in which it is purchased.	1.00
				Composite Score	**0.84**

TABLE 1.6-5

DARS SCORES: CO_2 EMISSIONS FROM KEROSENE COMBUSTION

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	9	The emission factor is based on a precise stoichiometric relationship.	9	Fuel purchases are measured using top-down statistics.	0.81
Source Specificity	9	The emission factor was developed specifically for kerosene combustion.	9	Fuel purchases are very closely correlated to the emissions process.	0.81
Spatial Congruity	9	U.S. emission factors are used, but the carbon coefficient for kerosene varies slightly depending on its source.	9	States use state-level activity data to estimate state-wide emissions.	0.81
Temporal Congruity	9	The emission factor is based on stoichiometry, not on measured emissions over a particular time frame. However, the emission factor should not vary significantly over the course of a year.	9	States use annual activity data to estimate annual emissions.	0.81
				Composite Score	**0.81**

TABLE 1.6-6

DARS SCORES: CO_2 EMISSIONS FROM COMBUSTION OF LIQUEFIED PETROLEUM GAS (LPG)

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	9	The emission factor is based on a precise stoichiometric relationship.	9	Fuel purchases are measured using top-down statistics.	0.81
Source Specificity	6	The emission factor is based on the emission factors for the three products collectively known as LPG--propane, butane and ethane--and the national proportions of their use. In addition, although the amount of propane used each year for heating will vary, the emission factor is not changed each year.	9	Fuel purchases are very closely correlated to the emissions process.	0.54
Spatial Congruity	9	U.S. emission factors are used, but the carbon coefficient for each product in LPG varies slightly depending on its source.	8	States use state-level activity data to estimate statewide emissions.	0.72
Temporal Congruity	9	The emission factor is based on stoichiometry, not on measured emissions over a particular time frame. However, the emission factor was assumed not to vary significantly over the course of a year.	8	States use annual activity data to estimate annual emissions.	0.72
				Composite Score	**0.70**

Note 1: Data on sales of propane, butane, and ethane (which make up LPG) are available from the American Petroleum Institute.
Note 2: Some ethane is used as a feedstock.

TABLE 1.6-7

DARS SCORES: CO_2 EMISSIONS FROM NATURAL GAS COMBUSTION

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	10	The emission factor is based on a precise stoichiometric relationship.	8	Fuel purchases are measured using top-down statistics.	0.80
Source Specificity	10	The emission factor was developed specifically for natural gas combustion.	9	Fuel purchases are very closely correlated to the emissions process.	0.90
Spatial Congruity	10	Natural gas from different sources is very homogenous in the amount of carbon per BTU.	8	States use state-level activity data to estimate state-wide emissions.	0.80
Temporal Congruity	10	The emission factor is based on stoichiometry, not on measured emissions over a particular time frame. However, natural gas produced at different times is very homogenous in the amount of carbon per BTU.	10	States use annual activity data to estimate annual emissions, and natural gas is typically combusted in the year in which it is purchased.	1.00
				Composite Score	**0.88**

Note: The ratings shown here are for measurements of natural gas based on BTU content, not measurements based on volume.

TABLE 1.6-8

DARS SCORES: CO_2 EMISSIONS FROM COAL COMBUSTION

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	8	The emission factor is based on a stoichiometric relationship, but a variety of coal types are used.	8	Fuel purchases are measured using top-down statistics.	0.64
Source Specificity	8	The emission factor was developed specifically for coal combustion.	8	Fuel purchases are closely correlated to the emissions process. However, data are not available for the consumption of coal by rank for industrial, commercial, or residential consumers.	0.64
Spatial Congruity	8	U.S. emission factors are used, but the carbon coefficient for coal varies depending on the source of the coal.	8	States use state-level activity data to estimate state-wide emissions.	0.64
Temporal Congruity	8	The emission factor is based on stoichiometry, not on measured emissions over a particular time frame. The emission factor may vary over the course of a year.	8	States use annual activity data to estimate annual emissions.	0.64
				Composite Score	**0.64**

Note: The emission factor scores are for state-specific emission factors (i.e., emission factors developed for the state in which the coal was produced).

TABLE 1.6-9

DARS SCORES: CO_2 EMISSIONS FROM OXIDATION OF LUBRICANTS

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	7	The emission factor is based on a stoichiometric relationship for one component of lubricants (i.e., motor oil).	4	Sales of lubricants in each state are based on national sales and each state's 1977 proportion of national sales. Oxidation of lubricants is approximated as a percentage of lubricant sales.	0.28
Source Specificity	8	The emission factor for oxidation of lubricants (a category comprising motor oil and other products) is based on the factor for motor oil alone; however, the range in emission factors for the different products is small.	8	Lubricant purchases are correlated to the emissions process.	0.64
Spatial Congruity	9	U.S. emission factors are used, but the carbon coefficient for each product in the "lubricants" category varies slightly depending on its source.	9	States use state-level activity data to estimate state-wide emissions.	0.81
Temporal Congruity	8	The emission factor is based on stoichiometry, not on measured emissions over a particular time frame. The emission factor may vary over the course of a year.	9	States use annual activity data to estimate annual emissions.	0.72
				Composite Score	**0.61**

TABLE 1.6-10

DARS SCORES: CO_2 EMISSIONS FROM COMBUSTION OF MISCELLANEOUS PETROLEUM PRODUCTS

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	6	The emission factor is based on a stoichiometric relationship. A number of products are included in the "miscellaneous petroleum products" category. Moreover, the relationship is based on highly uncertain storage factors for the various products.	7	Fuel purchases are presumed to be measured using top-down statistics.	0.42
Source Specificity	4	Because of the number of products in the "miscellaneous petroleum products" category, the emission factor is not specific to any given product. Storage is estimated for broad categories of products.	8	Fuel purchases are correlated to the emissions process.	0.32
Spatial Congruity	6	U.S. emission factors are used, but the carbon coefficient for each product in "miscellaneous petroleum products" varies depending on its source.	6	States use state-level activity data to estimate state-wide emissions, but some products may be used out of state.	0.36
Temporal Congruity	7	The emission factor is based on stoichiometry, not on measured emissions over a particular time frame. The emission factor is expected to vary over the course of a year.	8	States use annual activity data to estimate annual emissions.	0.56
				Composite Score	**0.42**

7

REFERENCES

Electrical World. 1999. *The Directory of Electric Power Producers and Distributors*, 107th edition. (New York: McGraw-Hill).

EIA. 1997a. *Cost and Quality of Fuel for Electric Utility Plants 1996*. Energy Information Administration, U.S. Department of Energy. DOE/EIA-0191(96). Internet address: http://www.eia.doe.gov/bookshelf.html .

EIA. 1997b. *Quarterly Coal Report: April-June 1997*. Energy Information Administration, U.S. Department of Energy. DOE/EIA-0121(97/2Q). Internet address: http://www.eia.doe.gov/bookshelf.html .

EIA. 1997c. *State Energy Data Report 1995*. Energy Information Administration, U.S. Department of Energy. DOE/EIA-0214(95). Internet address: http://www.eia.doe.gov/fueloverview.html#state .

EIA. 1997d. *Annual Energy Review 1996.* Energy Information Administration, U.S. Department of Energy. DOE/EIA-0384(96). Internet address: http://www.eia.doe/bookshelf.html .

EIA. 1997e. *Electric Power Annual 1996: Volume 1*. Energy Information Administration, U.S. Department of Energy. DOE/EIA-0348(96/1). Internet address: http://www.eia.doe/bookshelf.html .

EIA. 1997f. *Emissions of Greenhouse Gases in the US, 1996*. Energy Information Administration, U.S. Department of Energy. DOE/EIA-0573(96). Internet address: http://www.eia.doe.gov/bookshelf.html

Grubb, M.J. 1989. *On Coefficients for Determining Greenhouse Gas Emissions from Fossil Fuel Production and Consumption.* Energy and Environmental Programme, Royal Institute of International Affairs, London, UK. April. Prepared for OECD/IEA Expert Seminar on Energy Technologies for Reducing Emissions of Greenhouse Gases, Paris.

Hong, B.D. and E.R. Slatick. 1994. *EIA Quarterly Coal Report*. January to March. 1994, 1.

IPCC. 1997. *Guidelines for National Greenhouse Gas Inventories*, 3 volumes: *Vol. 1, Reporting Instructions; Vol. 2, Workbook; Vol. 3, Draft Reference Manual.* Intergovernmental Panel on Climate Change, Organization for Economic Co-Operation and Development. Paris.

Marland, G., and A. Pippin. 1991. "United States Emissions of Carbon Dioxide to the Earth's Atmosphere by Economic Activity," *Energy Systems and Policy* 14:101-118.

Marland, G.,and R.M. Rotty. 1984. Carbon Dioxide Emissions from Fossil Fuels: A Procedure for Estimation and Results for 1950-1982. *Tellus* 36b:232-261.

Polk Company, National Vehicle Population Profile (NVPP) (Southfield, MI: R.L. Polk and Co.) 1998.

Rypinski. 1994. Memorandum of July 27, 1994 from Arthur Rypinski of the Energy Information Administration to Bill Hohenstein of U.S EPA regarding "Unpublished Data for Inventory."

U.S. EPA (U.S. Environmental Protection Agency). 1999. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 1997*. EPA 236-R-99-003. Internet address: http://www.epa.gov/globalwarming/inventory/1999-inv.html.

U.S. EPA (U.S. Environmental Protection Agency). 1998. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 1996*. EPA 236-R-98-006. Internet address: http://www.epa.gov/globalwarming/inventory/1998-inv.html.

8

APPENDIX

This appendix provides fuel resource profiles of electricity generation and related CO_2 emissions for California in 1994 and 1995. These profiles were prepared by the California Energy Commission, Energy Facilities Siting & Environmental Protection Division.

8.1 EXECUTIVE SUMMARY

The purpose of this report is to determine the contribution of carbon emitting (coal, natural gas and petroleum) and non-carbon emitting (nuclear, hydroelectric, geothermal, biomass and renewables) electric generation technology to electricity used in California. Electricity generation for California consists of power plants within California owned by electric utilities and independent power producers, and power plants outside of California owned by Californian electric utilities and non-Californian electric utilities. This report will characterize these electric generation sources as California utility, California non-utility, interstate purchases and international purchases. Power plants located outside of California but owned by Californian electric utilities will be classified as interstate electric generation sources.

The data used for this analysis is from the Department of Energy, and describes the fuel use and electricity generation for each utility owned power plant in the United States. Staff used this data to construct a fuel-resource profile of each utility reporting to the Department of Energy. The fuel-resource profiles describe what percentage of hydroelectric, nuclear, petroleum, coal, natural gas, geothermal, biomass and renewable resources make up each utility's electric power generation for a given historic year. By combining these profiles with the Department of Energy's records of bulk power transactions between utilities, staff estimated the resources used by out-of-state utilities to sell power to California. These profiles were also used to estimate the in-state utility generation. Staff used the Department of Energy's Annual Energy Review to determine the non-utility in-state generation.

This report shows that California relied more on out-of-state, coal-fired boilers than it did on nuclear or hydroelectric power in 1994, accounting for 20% of the generation for California. We can also see that increased hydroelectric generation (from 1994 to 1995) decreases the in-state, utility-owned, natural gas-fired generation. Approximately 50% of the CO_2 emissions from electricity generation for California occurs out-of-state. Approximately 50% of the CO_2 emissions from electricity generation for California are divided between in-state utility and non-utility resources.

8.2 INTRODUCTION

The purpose of this analysis is to develop fuel resource profiles of electric generation and the related CO_2 emissions that are either produced by California utilities, California non-utilities, interstate or international resources selling to California. To determine the profiles staff used the Energy Information Administration's (EIA) Monthly Generator Report (Form 759)[i], Bulk Power Transfer database (Form 412)[ii] and Annual Electricity Report.[iii] Staff also used the Electric World Directory of Electric Power Producers[iv], and a best estimate of the fuel profile for the Western Area Power Administration (WAPA).[v]

Staff estimated the profiles for each utility by fuel resource type (natural gas, coal, nuclear, hydroelectric, etc.) based on their annual fuel use and electricity generation. Staff used the United States Environmental Protection Agency's (EPA) State Workbook of Methodologies for Estimating Greenhouse Gas Emissions[vi] to determine the CO_2 emission profile for each utility based on their fuel use and the carbon content of the fuel. Staff combined this information with the power transfer data from EIA to estimate the CO_2 emissions from California utility purchases from interstate or international resources. In a similar fashion, staff determined the California utility and non-utility electricity generation and associated CO_2 emissions.

This methodology is based on the following assumption: the electricity purchased from any utility is generated by a mixture of that utility's total on-line power plants. Now in reality, we know that utilities use specific power plants to fulfill specific electricity purchases. However, these purchases themselves have an effect on how the utility uses the rest of their power plants. Determining the total impact of the power purchase on the supplying utility is very complicated, and would need to identify changes in the power plant dispatch that occur each hour. To avoid this complexity, we make the aforementioned assumption.

Applying this methodology to investor owned utilities (i.e., PG&E or SCE) results in an acceptable estimation of the carbon emissions associated with the sale of electricity to other utilities (i.e., sale for resale). However, small utilities (i.e., SMUD, Imperial Irrigation District, etc.) very often sell more power than they produce themselves, which implies that they buy and re-sell power from other utilities. These situations are rare and do not involve a significant amount of power, but it does mean that when focusing on municipalities a different methodology must be employed. This paper will focus on California in general, and not any one utility.

8.3 RESULTS

Total Electricity Generation for California in 1994

The total electricity generated for California in 1994 was 256,285 GWH and had a CO_2 emission of 129,879,773 tons. Table 1 shows the percentage breakdown of the fuels and resources used for generation in 1994. Table 2 shows the corresponding CO_2 emissions. Figure 1 was developed to better conceptualize the fuel resource profile for 1994, likewise Figure 2 was created to show the corresponding CO_2 emissions for that electricity production.

Table 1.8-1
Fuel Resource Profile of Total Electricity Generation for California in 1994
(All values are percents)

	California Generation		Power Purchases		
	Utility	Non Utility	Interstate	International	Total
Coal	0	1.16	18.87	0	20.04
Natural Gas	24.01	14.66	2.21	0.01	40.89
Petroleum	0.73	0.74	0.03	0.29	1.79
Nuclear	13.17	0	1.45	0	14.62
Hydroelectric	7.20	1.24	3.87	0.08	12.39
Geothermal	2.63	2.33	0.68	0.23	5.87
Biomass	0	2.05	0.02	0	2.07
Renewable	0	2.33	0.01	0	2.34
Total	47.74	24.52	27.14	0.61	100

Table 1.8-2
Fuel Resource Profile of CO_2 Emissions from Total Electricity Generation for California in 1994
(All values are percents)

	California Generation		Power Purchases		
	Utility	Non Utility	Interstate	International	Total
Coal	0	2.31	41.92	0	44.23
Natural Gas	27.75	17.72	2.91	0.01	48.39
Petroleum	1.23	1.78	0.09	4.19	7.29
Nuclear	0	0	0	0	0
Hydroelectric	0.09	0	0	0	0.09
Geothermal	0	0	0	0	0
Biomass	0	0	0	0	0
Renewable	0	0	0	0	0
Total	29.06	21.82	44.92	4.20	100

Figure 1.8-3

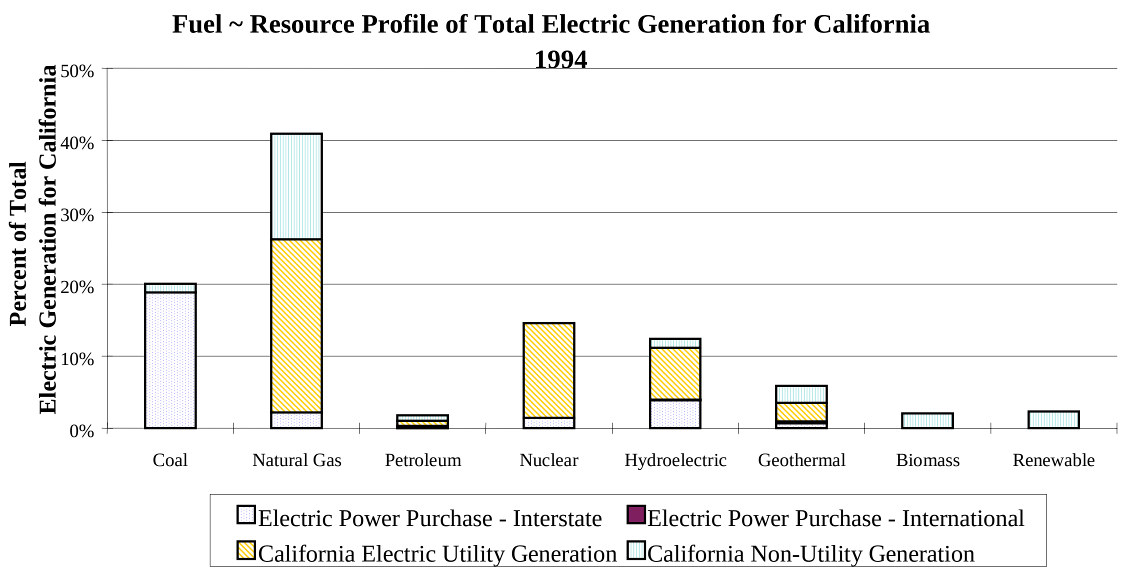
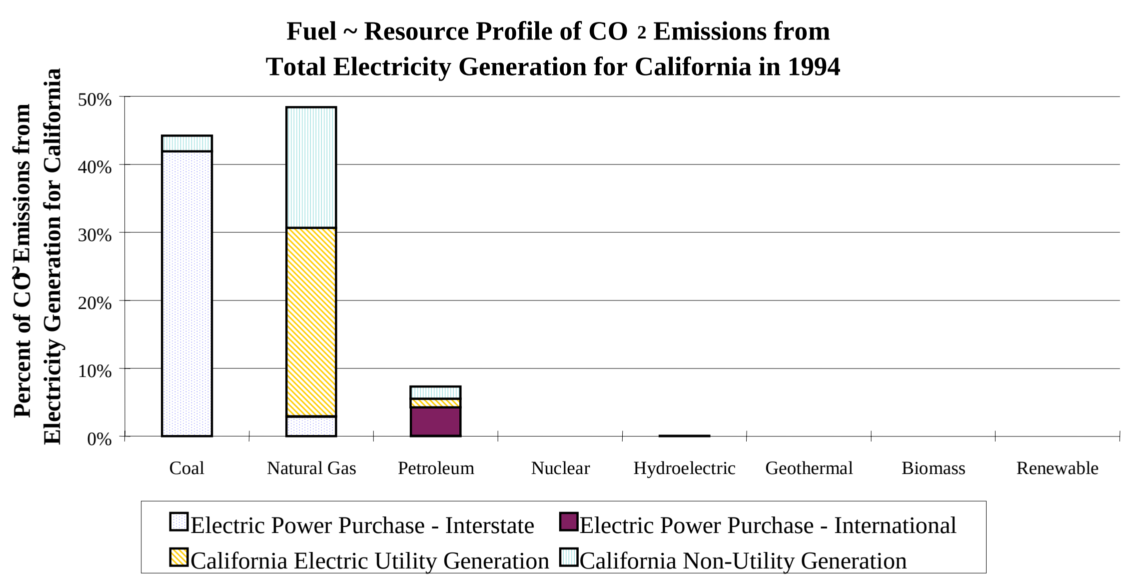


Figure 1.8-4



Total Electricity Generation for California in 1995

The total electricity generated for California in 1995 was 249,745 GWH and had a CO_2 emission of 114,793,380 tons. Table 3 shows the percentage breakdown of the fuels and resources used for generation in 1995. Table 4 shows the corresponding CO_2 emissions. Figure 3 was developed to better conceptualize the fuel resource profile for 1995, likewise Figure 4 was created to show the corresponding CO_2 emissions for that electricity production.

Table 1.8-5
Fuel Resource Profile of Total Electricity Generation for California in 1995
(All values are percents)

	California Generation		Power Purchases		
	Utility	**Non Utility**	**Interstate**	**International**	**Total**
Coal	0	1.19	17.65	0.03	18.87
Natural Gas	15.65	15.05	2.36	0.005	33.07
Petroleum	0.20	0.76	0.04	0.43	1.43
Nuclear	12.11	0	2.33	0	14.44
Hydroelectric	16.05	1.27	4.82	0.16	22.31
Geothermal	1.84	2.39	0.77	0.34	5.34
Biomass	0.0008	2.10	0.025	0	2.13
Renewable	0.006	2.39	0.019	0	2.42
Total	45.86	25.16	28.02	0.965	100

Table 1.8-6
Fuel Resource Profile of CO_2 Emissions from Total Electricity Generation for California in 1995
(All values are percents)

	California Generation		Power Purchases		
	Utility	**Non Utility**	**Interstate**	**International**	**Total**
Coal	0	2.31	43.52	0.08	46.22
Natural Gas	20.61	20.05	3.55	0.007	44.22
Petroleum	0.39	2.02	0.177	6.88	9.46
Nuclear	0	0	0	0	0
Hydroelectric	0.1096	0	0	0	0.1096
Geothermal	0	0	0	0	0
Biomass	0	0	0	0	0
Renewable	0	0	0	0	0
Total	21.10	24.69	47.24	6.97	100

Figure 1.8-7

Fuel ~ Resource Profile of Total Electric Generation for California 1995

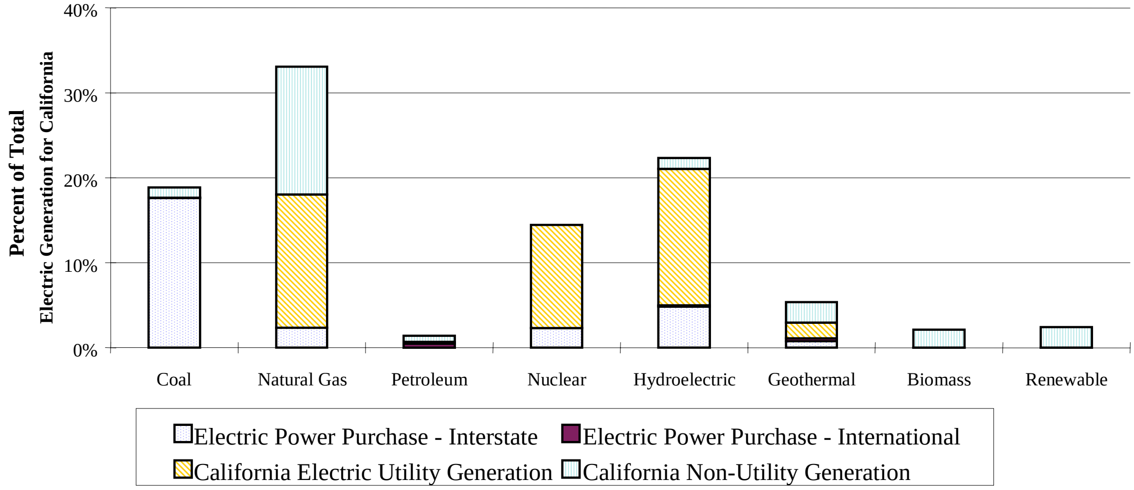
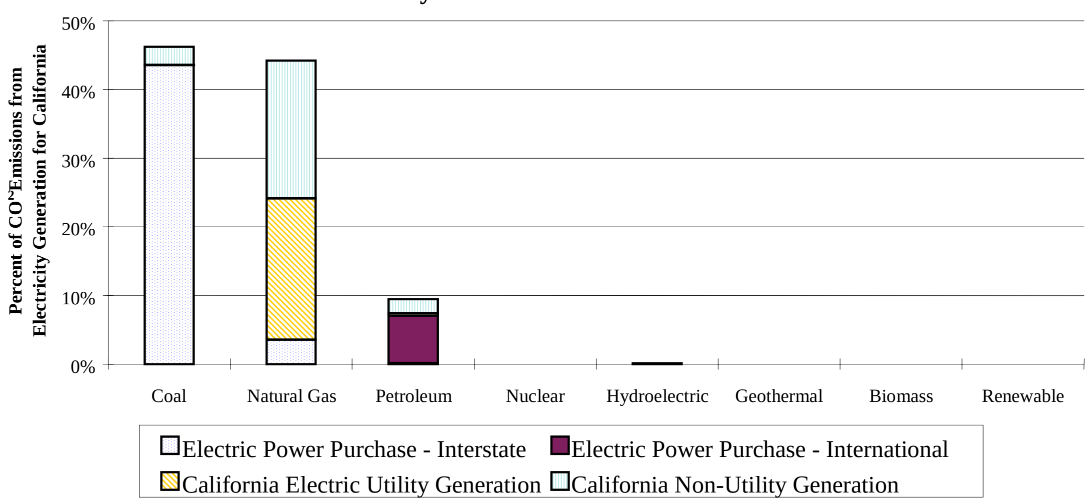


Figure 1.8-8

Fuel ~ Resource Profile of CO_2 Emissions from Total Electricity Generation for California in 1995



---

i Department of Energy, Energy Information Administration, Form 759, “Monthly Power Plant Report,” pertaining to years 1994 and 1995.

ii Department of Energy, Energy Information Administration, “Electric Power Annual,” using Forms 412, 759, 767, 826, 860, 861, 867, FE-781R, FERC-1, FERC-423, OE-411, pertaining to years 1994 and 1995.

[iii] Department of Energy, Energy Information Administration, "Annual Energy Review," Form 867 "Annual Non-Utility power Producer Report, pertaining to year 1995.

[iv] "Electrical World Directory of Electric Power Producers, 1996" 104th edition, Electric World.

[v] Conversation with Linda Kelly and Jim Hoffsis (California Energy Commission, Energy Forecasting & Resource Assessment Office) regarding the assumptions made with respect to the Western Area Power Administration and Western Systems Coordination Council in the 1994 Electricity Report as to how they fulfill their contract obligations. January 12, 1996.

[vi] State Workbook, "Methodologies for Estimating Greenhouse Gas Emissions," Second edition; Office of Policy, Planning and Evaluation. US Environmental Protection Agency, January 1995.